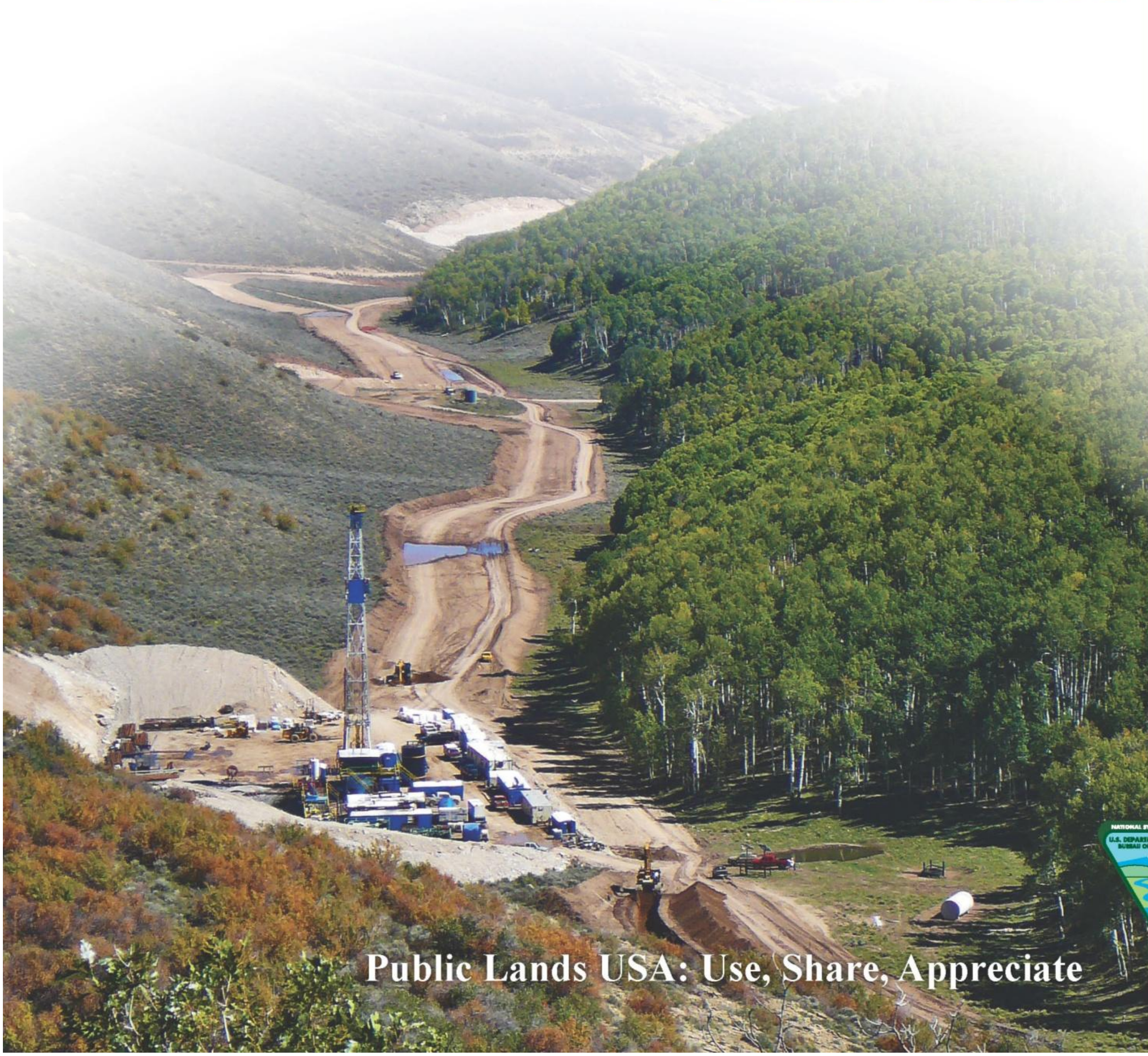
BLM

Appendix H

Oil and Gas Operations in the White River Field Office



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1.0 Geophysical Exploration

Oil and gas can be discovered by direct or indirect exploration methods, such as the mapping of rock outcrops, seeps, borehole data, and remote sensing data. In many cases, indirect methods, such as seismic, gravity, and magnetic surveys are required to delineate subsurface features that could contain oil and gas. Geophysical exploration could provide information that increases the chances of drilling a discovery well, as well as information that could discourage drilling and the associated surface disturbance. More sophisticated geophysical techniques, such as three-dimensional seismic surveys, could supply enough information to model a reservoir and optimize drilling to prevent excess wells and the associated surface disturbance. Economics and past information also play a role in determining the method used.

1.1 Seismic Reflection Surveys

Seismic prospecting is the best and most popular indirect method for locating subsurface structures and stratigraphy that might contain hydrocarbons. Seismic energy (shock waves) is induced into the Earth using one of several methods. As these waves travel downward and outward, they encounter various rock strata, each having a different seismic velocity characteristic. As the wave energy encounters the interface between rock layers, where the lower layer is of lower seismic velocity, some of the seismic energy is reflected upward. Sensing devices, commonly called geophones, are placed on the surface to detect these reflections. The geophones are connected to a recording truck that stores the data. The time required for the shock waves to travel from the shot point down to a given reflector and back to the geophone is related to depth, and this value is mapped to give an underground picture of the geologic structure.

There are many methods available today that an explorationist can use to induce the initial seismic energy into the Earth. All methods require preliminary surveying and laying of geophones. The thumper and vibrator methods pound or vibrate the ground to create a shock wave. Usually large trucks are used, each equipped with vibrator pads (about 4 feet square). The pads are lowered to the ground, and vibrators on all trucks are triggered electronically from the recording truck. Information is recorded, and then the trucks move forward a short distance, and the process is repeated. Less than 50 square feet of surface area is required to operate the equipment at each test site. The trucks are equipped with large flotation type tires, which reduce the impact of driving over undisturbed terrain.

The drilling method uses vehicle-mounted or heli-portable drills that drill small-diameter holes to depths down to 100 feet. Depending on type of survey, over 100 holes are drilled per mile of line. Usually, a 20-pound charge of explosives is placed in the hole, covered, and detonated. The detonated explosive sends a shock wave below the Earth’s surface that is subsequently reflected back to the surface from various subsurface rock layers. In rugged topography, a portable drill is sometimes carried in by helicopter. In remote areas where there is little known subsurface data, a series of short seismic lines might be required to determine the subsurface geology. Subsequently, more extensive seismic lines are arranged to obtain the greatest amount of geologic information.

Seismic information can be obtained in two- (2D) or three- (3D) dimensional configurations. To obtain 3D seismic information, the seismic sensors and energy source are located along lines in a grid pattern. This type of survey differs from the more common 2D surveys because of the large volume of data and the intensive computerization of the data. The results are expensive to obtain but give a more detailed and informative subsurface picture. The orientation and arrangement of the components in 3D seismic surveys are less tolerant of adjustments to the physical locations of the lines and geophones, but they are also more compact in the area they cover. Although alignment can be fairly critical, spacing of the lines can often be changed to significantly increase the information collected. The depth of the desired geologic information dictates the spacing of the grid lines, with smaller spacing detailing shallower formations. The 3D surveys are more detailed and are usually conducted after 2D surveys or drilling has delineated a geologic prospect. Extensive computer processing of the raw data is required to produce a useable seismic section from which geophysicists can interpret structural relationships to depths of 30,000 feet or more. The effective depth of investigation and resolution are determined, to some degree, by which method is used.

A typical drilling seismic operation can use 10 to 15 people operating 5 to 7 trucks. Under normal conditions, 3 to 5 miles of line can be surveyed each day using the explosive method. Larger seismic operations may require up to approximately 160 personnel on-site during project operations. Work day shifts are 13-14 hour days, although some workers may occasionally be present earlier or later during the day, if necessary. The vehicles used for a drilling program include several vehicle-mounted or heli-portable drill rigs, helicopters, water trucks, a computer recording truck, and several light pickup trucks for the surveyors, shot hole crew, geophone crew permit man, and party chief.

Use of off-highway vehicle (OHV) travel may be authorized to carry out cross country tasks. Vehicles are spread out so that vehicle routes are not straight, and vehicles do not retrace the same route. In some cases, this approach has prevented the establishment of new vehicle routes and has reduced impacts. Drilling water, when needed, is usually obtained from a permitted source.

Reconnaissance type surveys of gravity and geomagnetic can be run in areas where there is limited information with the attendant lower costs and less impact. More expensive and higher impact seismic surveys are run when more detailed information is required.

2.0 Geophysical Management (Permitting Process)

Geophysical operations on and off an oil and gas lease are reviewed by the appropriate federal surface management agency (SMA) (e.g., BLM, Bureau of Reclamation, or USFS). Effective administration and surface protection can only be accomplished through close cooperation between the operator and the affected agency. The responsibilities of the geophysical operator and the Authorized Officer are as follows (The Gold Book, DOI and USDA 2007).

<u>Geophysical Operator</u>: An operator is required to file with the Authorized Officer a “Notice of Intent to Conduct Oil and Gas Exploration Operations.” The Notice of Intent shall include site-specific project information and field techniques to minimize surface impacts; a map showing the location of the proposed 2D geophysical lines or 3D source and receiver proposed locations; all access routes and ancillary facilities; and a proposed schedule of field activities.

- The map should be at a minimum scale of one-half inch equals 1 mile; however, a 1:24,000 USGS topographic map is recommended.
- The party filing the Notice of Intent should be bonded. When applicable, a copy of the bond or other evidence of satisfactory bonding must accompany the Notice of Intent. Holders of statewide or nationwide oil and gas lease bonds may satisfy this requirement by obtaining a rider to include coverage of geophysical operations.
- For geophysical operation methods involving surface disturbance, a cultural resources survey may be necessary. In some circumstances, sensitive or threatened and endangered species surveys may also be necessary.

- A pre-work field conference is recommended and may be conducted by the surface management agency.
- Earth moving equipment shall not be used without prior approval.
- Upon completion of operations, including any required reclamation, the operator is required to file a Notice of Completion (NOC) of Oil and Gas Geophysical Exploration Operations (BLM Form 3150-5).

Authorized Officer: The authorized officer will contact the operator after the Notice of Intent (BLM Form 3150-4) is filed and inform the operator of the practices and procedures to be followed and the estimated time frame for approval.

- The authorized officer will complete a final post-work inspection of the site and notify the operator that the terms and conditions of the Notice of Intent have been met or that additional action is required by the operator.
- Consent to release the bond or terminate liability will not be granted by the surface management agency until the operator has met the terms and conditions of the Notice of Intent. (e.g., NEPA, approved Form 3040-1) before commencing operations on BLM-administered lands.
- After the operations are completed, as specified by the Notice of Completion, the Authorized Officer should complete a final inspection and notify the operator if the terms and conditions of the Notice of Intent have been met or if additional action is required.
- Consent to release the bond or termination of liability should not be granted until the terms and conditions have been met.

2.1 State Standards

The operator is required to register with the Colorado Oil and Gas Conservation Commission (COGCC). COGCC standards for plugging shot holes and personnel safety will be followed.

2.2 Mitigation

Seasonal restrictions may be imposed to reduce conflicts with wildlife, watershed damage, and hunting activity.

The most critical management practice is compliance monitoring during and after seismic activity. Compliance inspections during the operation ensure that stipulations are being followed. Compliance inspections upon completion of work ensure that the lines are clean, and the drill holes are properly plugged.

3.0 Oil and Gas Leasing

Based on the Federal Onshore Oil and Gas Leasing Reform Act of 1987, all leases must be available for competitive lease sales. Lands for which bids are not received at the lease sale will be available for noncompetitive leasing for a period not to exceed 2 years. Competitive sales will be held at least quarterly and by oral auction. Competitive and noncompetitive leases are issued for a 10-year term or for as long as oil and/or gas are produced. The Federal Government receives yearly rental fees on non-producing leases. Royalty is received at the rate of 12.5 percent of the total saleable production, one-half of which is returned to the State of Colorado.

Lease stipulations may be attached to each parcel and become part of the lease after sale. Initially, stipulations are attached to a parcel by the State office leasing section from various databases. The parcel list is segregated and sent to the field office that has the majority of the parcel lands in its area. In the field office, the parcel is reviewed by a group of resource and National Environmental Policy Act (NEPA) specialists to ensure that lands are in conformance with the resource management plan (RMP), the stipulations are correct, and that any missing stipulations are included. This completes the process and allows the parcel to be included in a sale package.

The authorized officer has the authority to relocate, control timing, and impose other mitigation measures under Section 6 of the Standard Lease Form. This authority is invoked when lease stipulations are not attached to the lease, or new resources are discovered on a lease. Lease stipulations are conditions of lease issuance that provide protection for other resource values or land uses by establishing authority for delay, site changes, or the denial of operations within the terms of the lease contract. The stipulations are specified for each applicable parcel in the Notice of Competitive Oil and Gas Lease Sale and are intended to inform interested parties (potential lessees, operators) that certain activities will be regulated or prohibited unless the operator and the SMA arrive at an acceptable plan for mitigation of anticipated impacts. These stipulations are either attached to the entire lease, or by aliquot portions identifying the protection measure specific to the lease.

Lease stipulations are based on the perceived resource requirements and land uses as specified in NEPA documentation. New science, comprehensive documentation of resource requirements, land pattern interference, and ongoing monitoring of the effectiveness of a stipulation may allow granting of a waiver, exception, or modification to a stipulation. A lease stipulation “waiver” is a permanent exemption to a lease stipulation. An “exception” is a one-time exemption to a lease stipulation and is determined on a case-by-case basis. A “modification” is a change to the provisions of a lease stipulation, either temporarily, or for the term of the lease.

4.0 Drilling Permit Process

Onshore Oil and Gas Operations; Federal and Indian Oil and Gas leases; Onshore Oil and Gas Order Number 1, Approval of Operations; Final Rule issued March 7, 2007 under 43 CFR 3160. These procedures cover the full gamut of operations on federal minerals, from initial permitting of the well to subsequent operations and final abandonment. In 2009 the Colorado BLM entered into a Memorandum of Understanding (MOU) with U.S. Forest Service (USFS), Rocky Mountain Region and COGCC concerning oil and gas permitting on BLM and Forest Service lands. Under the MOU, operators on federal lands will be advised of their responsibility to comply with all applicable laws and regulations, including the COGCC rules.

In the initial permitting process, the operator selects the location of a proposed drill site. This selection is based on COGCC spacing requirements, the subsurface geology, the topography, and the avoidance of known protected surface resource values.

Location of wells and spacing requirements are established by the COGCC to protect the correlative rights of offsetting mineral owners and efficiently recover the resource. This applies to all mineral ownership (i.e., fee, State, and federal minerals). The spacing requirements are to be applied to the subsurface point of production. Wells must be drilled within 200 feet of the center of a legal subdivision, such as a quarter section, depending on the spacing assigned to the particular area. A proposed location may be moved beyond the designated tolerance by a spacing exception granted by COGCC. A spacing exception requires notification of the offsetting mineral lease owners. If there is a protest, the matter must be presented at a public hearing with full evidence of the need to relocate the well before a decision can be made by COGCC. The White River Field Office (WRFO) is subject to State spacing COGCC Rule 318, which for wells deeper than 2,500 feet would be about

40 acres; however wells may be approved at less than 40- acre spacing for efficient resource recovery. For wells shallower than 2,500 feet, the wells must be spaced at least 300 feet from the nearest well and a distance of at least 200 feet from the lease boundary. Forty acres is not a probable future spacing for the entire WRFO, except in specific instances, because spacing is based on the most efficient recovery of the reserves. The probable maximum subsurface density of wells is 40 acres throughout most of the WRFO, with certain areas having a subsurface density of 10 acres based on the currently projected recovery efficiencies and economics. Surface density of wells would be a variable based on the surface resource conflicts, economics of directional drilling and the subsurface density.

4.1 Permitting

After the operator makes a decision to drill a well, the well, access road, and pipeline can be surveyed and staked without notifying BLM. Cultural resource inventories can also be obtained without notice. An Application for Permit to Drill (APD) or Reenter, on Form 3160–3, is required for each proposed well, and for reentry of existing wells (including disposal and service wells). Further details on the APD process are found in Onshore Oil and Gas Order Number 1. Three methods of notification are as follows:

- Early Notification - The operator may wish to contact the BLM and any applicable SMA, as well as all private surface owners, to request an initial planning conference as soon as the operator has identified a potential area of development. Early notification is voluntary and would precede the Notice of Staking (NOS) option or filing of an APD.
- Notice of Staking Option - After the operator makes the decision to drill a well, it must decide whether to submit an NOS or an application to drill (APD). The NOS is an abbreviated notice that consists of an NOS form, a staked location map, and sketched site plan. This notice is posted for a 30-day public review. The NOS triggers the onsite inspection of the well, which determines whether there are any conflicts with critical resources, as well as provides the preliminary data to assess what additional items are necessary to complete the APD.
- Application for Permit to Drill - The operator can submit a completed APD in lieu of an NOS, but in either case, no surface disturbing activity can be conducted in conjunction with the drilling operations until the APD is approved by the Authorized Officer. Operators are encouraged to consider and incorporate BMPs into their APDs because BMPs can result in reduced processing times and reduced number of COAs.

If the APD option is used, an APD is submitted to the Authorized Officer, and a field inspection is held with the operator and any other interested party. The purpose of the onsite field inspection is to evaluate the operator’s plan, to assess the situation for possible impacts (surface and subsurface), and to formulate resource protection stipulations. To lessen environmental impacts, a site can be moved, reoriented, or resized, within certain limits, at the onsite inspection. The proposed access road or pipeline can also be rerouted. If necessary, site-specific mitigations are added to the APD as Conditions of Approval (COA) for protection of surface and subsurface resource values in the vicinity of the proposed activity.

The field office is responsible for preparing environmental documentation necessary to satisfy the NEPA requirements and provide any mitigation measures needed to protect the affected surface resource values. Consideration is also given to the protection of subsurface resources. Casing and cementing programs shall be conducted as approved to protect and/or isolate all usable water zones, lost circulation zones, abnormally pressured zones, and any prospectively valuable deposits of minerals. Usable water is defined as water containing 10,000 parts per million or less of total dissolved solids. Water of this quality is to be protected usually by surface casing and cement. Determining the depth of fresh water requires specific water quality data in the proposed well vicinity or geophysical log determination of water quality, depending on existing well proximity and log availability. If water quality data or logs from nearby wells are not available, the area within a 2-mile radius of the proposed well is checked for water wells. If wells exist, surface casing is required to be set below the deepest fresh water zone found in these wells, or below a depth reasonably estimated for future water wells. In the WRFO, usable water can be available to great depths and beyond the surface casing setting point. In this case, surface casing is set through the fresh surface waters, and cement is required to protect the remaining useable water from the underlying non-useable water. The depth of the casing is specified to be below a depth reasonably anticipated for future useable water recovery.

When final approval is given by BLM, the operator can commence construction and drilling operations. Approval of an APD is valid for 2 years. If drilling does not begin within the 2 years, the conditions of approval can be revised before extending the APD for 2 additional years. The operator is responsible for reclaiming any surface disturbance that resulted from its actions, even if a well was not drilled.

Economic conditions dramatically affect drilling activity. A downturn in the oil and gas market could create a significant decrease in the number of drilling wells within the WRFO. More information on drilling and production trends for the WRFO can be found in the reasonable foreseeable development (RFD) scenario created for the RMPA/EIS.

4.2 Standard Drilling Conditions of Approval

In addition to any conditions of approval that are developed during the environmental analysis, APDs are also subject to WRFO's standard drilling COAs which are listed below.

1. All operations, unless a variance has been granted in writing by the Authorized Officer, must be conducted in accordance with 43 CFR PART 3160 - Onshore Oil and Gas Operations, Onshore Oil and Gas Order No. 1; Approval of Operations on Onshore Federal and Indian Oil and Gas Leases; and Onshore Oil and Gas Order No. 2; Drilling Operations. If air or mist drilling is used, operations must be in accordance with Onshore Oil and Gas Order No. 2; Drilling Operations, Part E; Special Drilling Operations.
2. The operator is responsible for the actions of his subcontractors. A copy of the approved APD must be on location during construction, drilling, and completion operations.
3. Major deviations from the drilling plan require prior approval from the Authorized Officer. The operator shall verbally notify either the petroleum engineer or petroleum engineering technician 24 hours prior to the following operations to provide notice of:
    a. Well spud (Breaking ground for drilling surface casing)
    b. Running and cementing of all casing strings
    c. Pressure testing of blowout preventer equipment (BOPE) or any casing string
    d. Commencing completion operations

    A written sundry notice of the well spud must be submitted within five (5) working days.

4. All BOPE tests will be done by a tester and not by the rig pumps. The tests will include a low pressure test of 250 psi for five minutes prior to initiating the high pressure tests discussed in Onshore Order No. 2

5. No "new" hardband drill pipe abrasive to casing will be rotated inside the surface casing unless it can be shown to be casing friendly in the manufacturer's specifications. Hardband drill pipe will be considered new until it has been run at least once.
6. Drilling muds with chlorides testing in excess of 3,000 ppm or those containing hydrocarbons shall not be used in drilling operations until after the surface casing has been set. When drilling to set the surface casing, drilling fluid will be composed only of fresh water, bentonite and/or a benign lost circulation material – that is a lost circulation material that does not pose a threat to human health or the environment, e.g. cedar bark, shredded cane stalks, mineral fiber and hair, mica flakes, ground and sized limestone or marble, wood, nut hulls, corncobs, or cotton hulls.
7. During surface cementing operations, should cement not be circulated to surface the WRFO shall be verbally notified as soon as reasonably possible. A log acceptable to the WRFO shall be run to determine the top of cement prior to commencing remedial cementing operations. If cement is circulated to surface and subsequently falls back, top job(s) will be performed until cement remains at surface.
8. Due to the extensive lost circulation problems that are being encountered in the Piceance Basin during drilling operations from surface to total depth (TD), and given that all usable water zones, potential productive zones, and lost circulation zones shall be protected and/or isolated per Onshore Order No. 2, the White River Field Office requires sufficient volumes of cement be pumped to meet these requirements. Cement tops behind intermediate and production casing will be verified by an acceptable log to ensure compliance with this Order. We require cement to be run a minimum of 200 feet above the shoe of the previous casing string.
9. Chronologic drilling progress reports must be sent directly to the BLM White River Field Office on a daily basis, either electronically or by fax (970-878-3805) to the Petroleum Engineer and/or other designated petroleum engineering technicians until the well is drilled to total depth.
10. All drill cuttings shall be contained in a pit on the pad of the well being drilled, or hauled to an approved disposal site. All pits shall maintain a minimum of two feet of free board at all times.
11. For foam and ultralight cement jobs that are performed in cementing the intermediate or production strings, the operator will wait at least 36 hours for cement to harden before running a specialized log capable of reading pipe cement bond and verifying tops of cement. The White River Field Office shall be verbally notified prior to running such specialized log with enough advance notice to allow a representative from this office to witness. Logs showing pipe cement bond and tops of cement for intermediate and production cement jobs will be forwarded to the BLM.
12. One copy of all charted BOPE tests, logs, core descriptions, core analyses, well-test data, geologic summaries, sample descriptions, and all other surveys or data obtained and compiled during the drilling, workover, and/or completion operations, shall be filed with the completion report, Form 3160-4. The logs should be submitted in a digital format, on a CD. This completion report shall be filed within 30 days of completion of operations and submitted prior to, or along with the first production notice.
13. The WRFO requires the measurement of individual gas, oil (condensate) and water production streams at the wellhead, unless otherwise approved in advance by the BLM. The sales point for natural gas will be at the wellhead. All meters will be calibrated in place prior to any deliveries. The White River Field Office will be provided with a date and time for the initial meter calibration and all future meter proving and calibration schedules with enough advance notice, 24 hour minimum, to allow a representative from this office to witness. A copy of the meter proving and calibration reports will be submitted to the White River Field Office. Oil

(condensate) will be sold from secured tanks on location, unless otherwise approved in advance by the BLM.

4.3 Surface Disturbance Associated With Oil and Gas Drilling

Upon receiving approval to drill the proposed well, the operator moves construction equipment over existing roads to the point where the access road will begin. Generally, the types of equipment include trackhoe, dozers (track-mounted and rubber-tired), scrapers, and motor-graders. Moving equipment to the construction site requires moving several loads (some overweight and overwidth) over public and private roads. Existing roads and vehicle routes are improved in places and occasionally, culverts and cattle guards are installed as specified in the approved APD.

The length of the access road varies. Generally the route is selected to reduce impacts to resources identified in the NEPA document. Environmental factors or the landowner's preference might dictate a longer route. Roads are usually constructed with a l4-foot (single lane) or 24-foot (double lane) running surface depending on well type (multiple or single well pad). Soil texture, steepness of the topography, and moisture conditions might require surfacing (e.g., gravel, dust suppressants) the access road.

All soil material suitable for plant growth is first removed and stockpiled in a designated area. Sites on flat terrain usually require slightly more than removing the topsoil material and vegetation. Drilling sites on ridge tops and hillsides are constructed by cutting and filling portions of the location. The majority of the excess cut material is stockpiled in an area that will allow it to be easily recovered for rehabilitation. It is important to confine extra cut material in a stockpile rather than to cast it down hillsides and drainages where it cannot be recovered for rehabilitation.

The amount of level surface required for safely assembling and operating a drilling rig varies with the type of rig, the depth, type of the well, and number of wells on the pad. The size of a pad is primarily determined by the capacity of the reserve pits to hold the cuttings from all wells drilled on the pad, as well as having sufficient room for drilling and well completion operations. The average size for a single-well pad is 4 acres, 8 acres for an eight-well pad, and 12 acres for a sixteen-well pad. The number of optimal locations is finitely limited, therefore operators needs to optimize the location of future roads and wellpads for maximum benefit, and utilize directional drilling technology to target bottom-hole locations where there is steep terrain overhead (BLM, 2007a). In addition to the drilling rig footprint, a reserve pit is constructed, usually square or oblong, but sometimes in another shape to accommodate topography. Generally, the reserve pit is 8 to 12 feet deep, but could be deeper to compensate for smaller length and width or deeper drilling depths. Depending on the relationship of the location to natural drainages, it might be necessary to construct water bars or diversions. The amount of area disturbed for construction depends largely on the steepness of the slope. Depending on the soil permeability, pits may be lined with an impermeable material to contain the drilling fluids. If water is encountered while digging the reserve pit, a closed mud system, consisting of steel tanks, could be required. For oil base mud, closed systems are mandatory, and the mud and cuttings must be recycled or disposed of in an approved manner.

Moving a drill rig might require approximately 35 truck trips of construction equipment over public highways and private roads. Drill rigs for Coal Bed Natural Gas (CBNG) as compared to deep drilling rigs are smaller, require fewer loads, and are less structurally imposing.

Water for drilling and well completion may be hauled or piped to drilling locations. Water sources are usually commercial water sources or recycled water if drilling is below the surface casing and fresh water aquifer zones. When drilling commences, and as long as it progresses, water is continually transported to the rig location. Roughly 5,000 barrels of water are required to drill and 23,000 barrels for completion operations for an oil or gas well to the depth of 9,000 feet or greater. Generally, water required for completion operations is recycled to the extent practical, More water would be required if circulation is lost, or permeable zones that cannot withstand the pressure of the drilling fluid are encountered.

4.4 Issuance of Rights-of-Way

Rights of way (ROW) are required for all facilities, tank batteries, pipelines, powerlines, and access roads that occupy federally owned land outside the lease or unit boundary. When a third party (someone other than the operator) constructs a facility or installation on or off the lease, a ROW is also required. The ROW is issued by BLM.

5.0 Drilling Operations

This section describes more conventional or traditional drilling operation techniques. BLM encourages the use of other new alternative construction and drilling techniques and technologies designed to limit environmental effects.

5.1 Rotary Drilling

Initially, drilling proceeds rapidly because of the less competent nature of shallow formations. Drilling is accomplished by rotating the drill string and putting variable weights on the bit located at the bottom of the string. While drilling, the derrick and associated hoisting equipment bear a majority of the drill string’s weight. The combination of rotary motion and weight on the bit causes rock to be gouged away at the bottom of the hole. The rotary motion is created by a square or hexagonal rod, called a kelly, which fits through a square or hexagonal hole in a large turntable, called a rotary table. The rotary table sits on the drilling rig floor and as the bit advances, the kelly slides down through it. When the kelly has gone as deep as it can, it is raised, and a new piece of drill pipe about 30 feet in length is attached in its place. The drill pipe is then lowered, the kelly is reattached, and drilling recommences. When the bit becomes dull, it is necessary to “trip” the drill string and replace the bit. This is a time-consuming process of withdrawing 90-foot sections of the drill pipe until the bit is out of the hole. This process requires a large part of the total drilling time and could cause other hole problems. New bits constructed with modern metals and manufactured polycrystalline diamonds along with down hole mud motors have revolutionized drilling operations, whereby thousands of feet of hole can be drilled with one bit run. The mud motor is a positive displacement pump (moineau pump run in reverse) driven by high-pressure mud and is placed at the top of the bit to enable more rotational power to be transmitted to the bit and thus increase penetration rates.

Drilling mud is circulated through the drill pipe to the bottom of the hole, through the bit, up the annulus (i.e., the space around a pipe in a well bore) of the well, across a screen that separates the rock chips, and into holding tanks from which finer sediments settle from the mud before it is pumped back into the well. The mud is maintained at a required weight and viscosity to cool the bit, reduce the drag of the drill pipe on the sides of the hole, seal off any porous zones, contain formation fluids to prevent a blowout, and bring the rock chips to the surface for disposal. Various additives are used in maintaining the mud at the appropriate viscosity and weight. Most of the mud consists of bentonite. Some of the additives are caustic, toxic, or acidic, but these hazardous additives are used in small amounts during the drilling operations and later contained within the reserve pit.

Within the WRFO, drilling is usually accomplished with water or light mud to depths within about 1,000 feet of the prospective formation. Water and natural clays recovered during the drilling operation, or light drilling mud, allow fast drilling rates and the attendant reduction in mud chemicals. Once the bit reaches the target depth, the mud system is gradually made more sophisticated by addition of bentonite, chemicals, and natural weight materials to reduce water loss to the potential producing zones and to control the subsurface pressure. In almost all cases, the subsurface pressure is higher than an equivalent water column, and it is necessary to increase the mud weights to control the pressure and prevent a blowout or uncontrolled flow of formation fluids. Many wells are drilled in an underbalanced condition, whereby the mud pressure is slightly less than the formation pressure, which increases penetration rate and reduces the time on the well, or in the formations of interest. Drilling in this condition also reduces the potential of damaging the formation, with the attendant loss of flow capacity and recovery. The wells are always overbalanced for safety requirements when a bit trip is made, the well is logged, or the casing is installed.

Drilling operations are continuous, 24 hours a day, 7 days a week. The crews usually work three 8-hour shifts or two 12-hour shifts a day. Pickup trucks or cars are used for workers' transportation to and from the site. On remote isolated sites, a camp might be established to house the crews, which will reduce the travel requirements. Other operations, such as cementing, running casing, and rig maintenance will require road travel, sometimes with heavy equipment.

Upon completion of the drilling, a determination is made regarding the productive potential of the well. If oil or gas is not discovered in commercial quantities, the well is considered dry. The operator is then required to follow BLM procedures to properly plug the dry hole. The drill site and access road are then rehabilitated in accordance with the stipulations attached to the APD and the plugging approval. If the well is a producer, drilling rig operations continue until the production casing is cemented into the well before removing the drilling equipment from the location.

5.2 Logging

Geophysical logs are obtained by running various instruments into the hole on a wire cable. Logs are usually run at a depth point where casing will be installed. A log is not usually run before surface casing is set, but in most instances a log recording natural gamma radiation is run through the surface casing to determine the geology of that section. The logs can determine water resistivity, hydrocarbon saturations, natural gamma radiations, porosity of the rock by density, nuclear receptivity and sonic measurements, permeability, pressure, temperature, hole geometry, and subsurface track. Logs are used to evaluate whether the well is dry or has the potential for a satisfactory completion. Logs also delineate the various geologic horizons; hydrocarbon zones; fresh, usable, and unusable water; and sands, shales, limestone, coal, and other minerals. Logs are required to specify productive intervals so that they can be perforated and stimulated during the completion program. Normally in the WRFO, logs recording resistivity and a combined porosity log of density and nuclear receptivity are run in the well. The dual porosity logs are a direct indicator of gas because the measured values can be compared to provide contrasting porosit.

5.3 Casing

Various types of casing are placed in the drilled hole to enhance completion operations and safety. Casing is a string of steel pipe composed of approximately 40-foot lengths of pipe that are threaded together. Centralizers are attached to casing to ensure that the casing is centered in the hole. This practice improves the efficacy of cement jobs. Casing is cemented into the well to protect against migration of fluids along the annulus between the casing and the hole. Cementing isolates the formations so they can be completed and produced without interference from other zones containing hydrocarbons or water. Hole deviation, depth, bore hole environment, placement of centralizers, and a myriad of other factors affect the integrity of the casing and cement job, and must be considered in the original design.

Surface casing that is properly set and cemented also protects surface aquifers from contamination by drilling and production operations. Surface casing should be set to a depth greater than the deepest fresh water aquifer that could be reasonably developed. Usable water could exist at great depths but these aquifers are not normally considered to be important water sources. Surface casing is designed to be large enough to allow subsequent strings of smaller casing to be set as the well is drilled deeper. Cement is placed in the annulus of the surface casing from casing shoe to ground level. The surface casing is the first string on which BOPE is installed. The BOPE allows the well to be shut in at any time that conditions warrant, protecting against unanticipated formation pressures and allowing safe control of the well. Blowout preventer equipment is tested and inspected regularly by both the rig personnel and the inspection and enforcement branch of BLM. Minimum standards and enforcement provisions are part of Onshore Order No. 2.

Casing strings subsequent to the surface string are required to be cemented 200 feet above the bottom of the previous string. In the WRFO, the annulus (i.e., the space around a pipe in a well bore) is required to be filled with sufficient cement to provide adequate protection from interzonal migration of unsuitable water and hydrocarbons. Production casing or production liner is designed to provide isolation of oil and gas formations, and a high-pressure conduit to the hydrocarbon zones that allows stimulation of these intervals to improve the productivity.

During completion operations, the production casing or liner is perforated into zones containing the oil or gas. In the WRFO, the low permeability character of the productive formations requires these zones to be “fracked” or stimulated by treated fresh water and large quantities of sand, which improves the productivity to an economic rate. Generally, two and up to five stimulation treatments can be accomplished in each well. Roughly 50 percent of the stimulation fluid is produced within a couple of days, and the rest over an extended period at low rates. Fracs stay within the simulated reservoir, which is important to maximize the enhanced productivity. After completion operations are finished, wellhead equipment, consisting of various valves and pressure regulators, is installed to control the oil or gas flow to the production facilities and to safely shut-in the well under any conditions.

5.4 Hydraulic Fracturing

Hydraulic fracturing is the process of creating small cracks, or fractures, in deep, underground geological formations to liberate oil or natural gas and allow it to flow up the well for capture. To fracture the formation, fracturing fluids – approximately 99.5 percent water and sand, with the remaining percentage chemical additives – are injected down the well bore into the formation. The fluid, injected under pressure, causes the rock to fracture along weak areas. These fractures typically range from 0.1 to 0.3 inches in width, 20 to 300 feet in height, and 300 to 1,500 feet in length. When the fractures are complete, and pressure is relieved, the fluids flow back up the well where they are captured and stored for later treatment or disposal. As the fluids flow back up, sand remains in the fractures and props the rock open. This allows the oil and gas to seep from the rock into the pathway, up the well and to the surface for collection. In Colorado, the targeted formations for hydraulic fracturing are often more than 7,000 feet underground, and some 5,000 feet below any drinking water aquifers.

The COGCC rules require that operators publicly disclose the ingredients and concentrations of fracturing chemicals for each well within 60 days of completion. That information is required to be posted on the website www.fracfocus.org, which is searchable by county, operator and well. The website also provides information on chemicals used and their purpose. In addition, on May 4, 2012, the DOI released a draft rule requiring public disclosure of chemicals used in hydraulic fracturing and confirmation that wells used in fracturing operations meet appropriate construction standards.

5.5 Oil and Gas Exploratory Units

Surface use in an oil or gas field could be affected by unitization of the leaseholds. In areas of federal and mixed mineral ownership, an exploratory unit can be formed before a wildcat exploratory well is drilled. The boundary of the unit is based on geologic data and attempts to consolidate the interests in an entire structure or geologic play. The developers of the unit enter into an agreement to develop and operate as a single entity, regardless of separate lease ownerships. Costs and benefits are allocated according to agreed-upon terms. Development in a unitized field can proceed more efficiently than in a field composed of individual leases because competition between lease operators and drainage considerations is not a primary concern. Unitization also can reduce surface use requirements because all wells are operated as though under a single lease, and operations can be planned for more efficiency. Duplication of field processing facilities is eliminated, and consolidation of facilities into more efficient systems is probable. Unitization can also involve wider spacing than usual, or spacing based on reservoir factor rather than a set rule, which could result in fewer wells and higher recovery efficiency. Through planning, access roads are usually shorter and better organized, and facilities are usually consolidated.

5.6 Field Development

New field development is analyzed in an environmental assessment (EA) or environmental impact statement (EIS) after the sufficient confirmation wells are drilled. The operator generally can estimate the extent of drilling and disturbance required to extract and produce the oil and gas at that time. Many fields go through several development stages. A field can be considered fully developed, and can produce for many years when it is determined that a well can be drilled to a deeper pay zone, or a new interval is discovered to be economically attractive. In this case, there is typically less new disturbance because the old well bores or the old well pads are used for the new completions. A new stage of field development, such as infill drilling, can lead to increases in roads and facilities. All new construction, reconstruction, or alterations of existing facilities, including roads, flow lines, pipelines, tank batteries, or other production facilities must be approved by BLM and could require a new environmental document. Throughout field development, partial restoration and rehabilitation is required to reduce the surface impacts to the minimum required to produce the resource.

The most important factor in further development of an oil or gas field is the economics of production. When an oil or gas discovery is made, a well spacing pattern can be established before development drilling begins. This pattern is dependent on the current statewide or area wide spacing. Well spacing is regulated by COGCC, and factors considered in the establishment of a spacing pattern include data from the discovery well that translate into recovery efficiency. These data include porosity, permeability, pressure, composition of reservoir and fluids, depth of formations, well production rates, and the economic effect of the proposed spacing on recovery. These data are relatively sparse in the initial phase of development, and extended production permits refinement of these values. Because these data are so tentative, COGCC tends to define large spacing until the data are more conclusive. Spacing for oil wells usually varies from 40 to 320 acres per well but can be as small as 2.5 acres. Spacing for gas wells is generally from 160 to 640 acres per well, but can be as small as 10 acres if reservoir recovery efficiency dictates that spacing. Spacing requirements can pose problems in selecting an environmentally sound location or in the cumulative impacts. Reservoir characteristics determine the most efficient spacing to achieve maximum recovery. If an operator determines that a different spacing is necessary to achieve maximum recovery, the State (with input from BLM) may grant exceptions to the spacing requirements.

6.0 Production

Gas, oil, and water are being produced in the WRFO by means of natural pressure (plunger lifts) and artificial lift (gas and electric pumping units and submersible pumps).

6.1 Gas Production

A typical gas well facility consists of methanol injection equipment (to keep production and surface lines from freezing), separator (which separates gas, oil, and water), dehydrator (uses glycol or calcium chloride to extract entrained water in the gas), and an orifice meter. An intermitter is sometimes used to either shut-in the well to build up pressure, or to blow the well down if it is being loaded with fluid. If the gas well is producing some oil or condensate, oil tanks are used to store the oil or condensate until it is sold by truck or pipeline. Pipeline quality gas at the wellhead requires a minimum of processing equipment. As the quality of gas decreases with the increased presence of water, solids, or liquid hydrocarbons, the amount of processing equipment increases. Water or liquid hydrocarbons in the gas are removed before the gas is sold, usually in the separation equipment near the wellhead. If liquid hydrocarbons are present, storage facilities (tank batteries) are required to store the liquids until they accumulate in sufficient quantities to be hauled out by large trucks. Gas dehydration equipment might also be onsite to remove water entrained in the gas to a water content defined by pipeline specifications. Gas production data can be found in the RFD scenario for oil and gas that was developed for the revised RMP.

Gas that occurs with oil is separated by collecting it into feeder lines leading to compressors that boost the pressure to the transportation system, venting or flaring. If enough casing head gas is separated to make it economical for marketing, a plant can be constructed to process the gas, or a pipeline can be constructed to carry the product to an existing plant. If the volume of casing head gas is insufficient to warrant treatment in a gas plant, it is usually used as fuel for pump engines in the field, or as heating fuel for the heater-treaters. Gas may be with written permission be flared or vented into the atmosphere if the quantity exceeds the fuel requirements on the lease but is not recoverable in commercial quantities.

6.2 Oil Production

In the WRFO, oil is generally produced using artificial lift methods (pump units). The oil production equipment, such as heater-treater, tank battery, and holding facility for production water, are either placed on a portion of the location (on cut rather than fill) and located a safe distance from the wellhead, or placed as a centralized facility that services a number of wells with pipeline connections. The heater treater and tanks are surrounded by earthen dikes to contain accidental spills. Either all the facilities or only the produced water pit (if present) will be fenced. Production facility colors are required to be from the standard color chart and are specified in the APD COAs.

Production from several wells on one lease can be carried by pipeline to a central tank battery. Use of a central tank battery can depend on whether the oil is from the same formation, the same lease ownership, or multiple lease ownerships and formations, or whether a commingling agreement is approved. Because of the nature of the oil, adequate separation of oil and water is only obtained through applications of heat. The fluid stream arrives at a separator point where the flash gas is taken off. In most cases, this flash gas is used for lease operations. The remainder of the flash gas is either compressed and sold or flared. Flash gas is defined as solution gas liberated from the oil through a reduction in pressure. Water and oil are also being separated at this point by gravity segregation. The oil is sent to storage tanks, and the water is sent to a disposal or injection facility. Two main methods of oil measurement used in the WRFO are lease automatic custody transfer units and tank gauging. Measurement is required by 43 CFR 3162.7-2 and Onshore Order No. 4 to ensure proper and full payment of federal royalty.

Oil wells can be completed as flowing (those wells with sufficient underground pressure to raise the oil to the surface), or if the pressure is inadequate, they are completed with the installation of subsurface pumps. The subsurface pumps are usually mechanically powered by a pumping unit. Pumping units come in a variety of sizes, the larger ones reaching a height of 30 to 40 feet. The units are powered by internal combustion engines or electric motors. Fuel for the engines may be casing head gas or propane. In cases where large volumes of water are produced with the oil, electric submersible pumps can be installed. These pumps could produce up to 6,000 barrels of fluid per day at an oil cut of ½ of 1 percent oil. Oil production data can be found in the RFD scenario for oil and gas that was developed for the revised RMP.

6.3 CBNG Production

Coalbed natural gas production combines high water production rates of some oil fields with low-pressure operations of some gas fields. Because of the reservoir characteristics of coal, high water production rates are initially required to dewater the reservoir and allow gas to be liberated from cleat surfaces (i.e., the vertical cleavage in coal seams) within the coal. In a coal reservoir, gas is primarily trapped on the face of the coal within the cleat system by molecular attraction. Pressure must be reduced to liberate the gas molecules from the coal face. The production history shows that water production rates begin high, with little or no gas. The water rate then drops at a constant rate, with increasing gas rates until a maximum gas rate is achieved relative to the original gas saturation and reservoir pressures. The gas rate then declines to the economic limit. This process is the exact opposite of that associated with most oil and gas production, which starts at high hydrocarbon rates and low water rates and advances to low hydrocarbon rates and high water rates. The reservoir depths of CBNG production are generally shallow (less than 5,000 feet) compared with most oil and gas production in the WRFO. The depth limit is based on coal permeability, which is highly sensitive to overburden weight. A CBNG operation usually consists of a high-capacity submersible or progressive cavity pump, with water produced out of the tubing, and low-pressure gas produced out of the casing. Centralized facilities collect the gas for compression to pipeline pressures and the water for disposal. Electric power is usually used to power the well pumps and is connected to the well by a subsurface cable laid with the water and gas lines. The producing well pad is very small, with only the wellhead and an insulating house to cover the wellhead. The centralized production facilities contain well header buildings where the individual well gas is measured, and where house collection tanks, injections wells, and pumps for disposal of the water as well as multistage compressors that bring the very low pressure gas to sales line pressure. Sometimes the water can be disposed of in the local drainages if the Colorado Department of Public Health and Environment, Water Quality Control Division (CDPHE) and the BLM approve this type of disposal. Currently in the WRFO, CBNG production is in its infancy, and little history is available regarding its economics and production rates. The RFD has further discussions on pilot projects, production, and the future prognosis of CBNG development within the WRFO.

6.4 Water Production

Produced water associated with oil, gas, or CBNG is disposed of by trucking or piping the water to an authorized disposal pit, placing the water in lined pits, discharging the water into surface drainages, or through subsurface injection. Water disposal is controlled by the COCGG for subsurface disposal and secondary recovery purposes. The quality of the water often dictates the appropriate disposal method, and CDPHE has primacy through the Environmental Protection Agency (EPA) to approve surface disposal of this water. Produced water is also used in enhanced recovery projects. The RFD contains further discussions on produced water production rates.

6.5 Production Problems

Weather extremes pose problems for producers by causing roads to become impassable, equipment to malfunction, and flow lines, separators, and tanks to freeze up. Other problems producers may encounter in the area are production of H_2S, CO_2, and paraffin; corrosion; electrolysis; and broken flow lines

6.6 Secondary and Enhanced Oil Recovery

Gas reservoirs typically have no secondary recovery associated with the recovery of gas because natural gas is produced by expansion resulting from the reduction of reservoir pressure. A high reservoir recovery factor can be expected from this expansion process unless the reservoir is of such low permeability that economics becomes a factor in the recovery efficiency. Economics is a determining factor because of the expense of operating compression facilities to reduce the reservoir pressure to the minimum.

Secondary recovery in coal reservoirs has been tested in the San Juan Basin and found to be technically feasible. This recovery process involves the molecular replacement of natural gas by CO_2 or nitrogen, and has also been touted as a method of sequestering CO_2 to remove the greenhouse gas from the atmosphere. An oil reservoir typically contains oil, gas, and water trapped within the rock matrix under pressure. Because of the pressure, much or all of the gas is dissolved in the oil. “Primary drive” is accomplished by expanding gas in solution, which forces oil out of the reservoir into the well and up to the surface. Oil flowing out of the reservoir drains energy from the formation and the primary drive diminishes. To keep oil flowing in the reservoir, pressure drawdown is required, and subsurface pumps could be used to lift oil to the surface. As reservoir pressures continue to drop, solution gas in the oil escapes, forming bubbles in the pore space. These bubbles further retard the flow of oil and increase the gas saturation and the flow of solution gas. This process accelerates as the pressure declines, and at some point, production rates become uneconomical, with as much as 80 percent of the original oil remaining in the reservoir. Currently, in the United States, primary oil recovery accounts for less than half of the current oil production. The remaining oil is produced by secondary and enhanced recovery techniques.

Two basic secondary recovery methods are in use—water flooding and displacement by gas. The preferred secondary recovery method is water flooding, which involves injecting water into oil reservoirs to maintain or increase pressure. The process is usually most efficient when the pressure has not fallen to the point where the reservoir is highly saturated with gas. Reservoir heterogeneity in the form of fractures, directional permeability, and thin zones could limit the success of this process.

The process of injecting gas is a less popular secondary recovery technique. Historically, produced gas was considered a waste product and was flared (burned) at the point of production. Later, it was recognized that the energy could be conserved and the recovery of oil increased if the produced gas was reinjected into the reservoir. Increased production was achieved by maintaining reservoir pressure by injecting the gas into the existing gas cap and also by injecting the gas directly into the oil-saturated zone, creating an immiscible gas drive that displaced the oil. To achieve miscibility, the reservoir must have reasonably high pressures and temperatures and contain high-gravity oil. Many gas injection projects use the water and gas (WAG) process, which is injecting water and gas alternately to achieve better contact with the oil within the reservoir. Currently, the high price and demand for natural gas has precluded this type of secondary recovery.

The term “enhanced recovery” is used to describe recovery processes other than the more traditional secondary recovery procedures. These enhanced recovery methods include thermal, chemical, and miscible (mixable) drives. Currently, no enhanced recovery techniques are being implemented within the WRFO, but it is unknown whether these techniques could be applicable in the future based on economics and new discoveries.

Some reservoirs contain large quantities of heavy oil that cannot be produced using normal or secondary methods. These reservoirs can be stimulated by thermal drive processes in which heat is introduced from the surface or developed in place in the subsurface reservoir. In the surface introduction process, hot water or steam is injected. Raising the temperature of heavy oil reduces the viscosity and makes the oil more mobile. Thermal recovery techniques are not likely to be tried in the WRFO because the oils in this area are not heavy oils. In the in-situ process, both heavy and light oils can be processed. Spontaneous or induced ignition within the reservoir is induced by injected air to develop a fire front that burns the hydrocarbons. Evaporation of the lighter ends immediately ahead of the fire front, and later condensation is the primary recovery mechanism. The remaining hydrocarbons are consumed by the fire and are generally not considered of any value. These techniques are very expensive and must have large reserves and thick pay zones to be economical. It is unlikely these techniques will be used within the WRFO in the immediate future unless new discoveries are made.

Several chemical drive techniques are currently in use, including polymer flooding, caustic flooding, and surfactant-polymer injection. These methods attempt to change reservoir conditions to allow recovery of additional oil. Caustic and surfactant-polymer flooding have not been economical in the past, and unless a breakthrough in technology is achieved, these techniques will probably not be considered during the planning period. Polymer flooding is an economically viable process but is used mainly in viscous reservoirs with high permeability. Currently, no such reservoirs exist in the WRFO but future discoveries could be made.

6.7 Gas Storage

Pipeline-quality gas can be stored in good quality reservoirs with sufficient sealing parameters. This gas is pumped into the reservoir during nonpeak, usually lower priced time periods, and then pumped out into the transmission lines at times of peak demand and higher prices. The price differential pays for the governmental fees required the use of the storage reservoir and the injection/compression costs required to store and retrieve the gas. Gas storage also serves as a buffer for cold periods when demand is high and levels out the summer slack period of production. There are no active gas storage reservoirs within the WRFO.

7.0 Plugging and Abandonment Of Wells

The purpose of plugging and abandoning a well is to prevent fluid migration between zones, to protect mineral and water resources from damage, and to restore the surface area. Each well must be handled individually because of a combination of factors, including geology, subsurface well design, and specific rehabilitation concerns; therefore, only minimum requirements can be established, and these must be modified for individual wells.

The first step in the plugging process is the filing of the Notice of Intent to Abandon. This notice is reviewed by both the SMA and WRFO petroleum engineer. The notice must be filed and approved before plugging a previously producing well. Verbal plugging instructions can be given for plugging current drilling operations, but a notice must be filed after the work is completed. If usable fresh water was encountered while the well was being drilled, the SMA may be allowed, if interested, to assume future responsibility for the well, and the operator will be reimbursed for the attendant costs. This assumption of responsibility becomes effective after the deeper zones are plugged back to the usable water zone. Usually the operator is more than satisfied to remove the surface reclamation liability and will not charge for the remaining well equipment.

The operator's plan for securing the hole is reviewed. The minimum requirements, as stated in Onshore Order No. 2, are as follows: In open hole situations, cement plugs must extend at least 50 feet above and below zones that have fluid with the potential to migrate, zones of lost circulation (this type of zone could require an alternate method to isolate it), and zones of potentially valuable minerals. Thick zones may be isolated using cement plugs across the top and bottom of the zone. In the absence of productive zones and minerals, long sections of open hole may be plugged with cement plugs placed every 3,000 feet. In cased holes, cement plugs must be placed opposite perforations and extending 50 feet above and below, except where limited by plug back depth. The length of the plug is 100 feet plus 10 percent per 1,000 feet (i.e., at 10,000 feet). The plug will be 200 feet long.

Cement plugs could be replaced with a cement retainer, if the retainer is set 50 feet above the open perforations and the perforations are squeezed with cement. A bridge plug could also be used to isolate a producing zone and must be capped, if placed through tubing, with a minimum of 50 feet of cement. If the cap is placed using a dump bailer, a minimum of 35 feet of cement is required. A dump bailer is an apparatus run on wire line to convey the cement to the bottom of the hole. In the event that the casing has been cut and recovered, a plug is placed 50 feet within the casing stub, and the 100 feet plus 10 percent per 1,000 feet rule is used for the space above the cutoff point. In all cases, a plug is set at the bottom of the surface casing that has a volume of cement using the 100 feet plus 10 percent per 1,000 feet rule. This could require perforating the casing and circulating or squeezing cement behind the production casing if that casing is not removed. Annular space at the surface will be plugged with 50 feet of cement using small-diameter tubing or by perforating and circulating cement.

If the integrity of a plug is questionable, or the position is extremely vital, it can be tested with pressure or by tagging the plug with the tubing or drill string. Tagging the plug involves running a pipe into the hole until the plug is encountered, and placing a specified amount of weight on the plug to verify its placement and competency. The surface plug within the casing must be a minimum of 50 feet. The interval between plugs must be filled with mud that will balance the subsurface pressures, and if this balance point is unknown, a minimum of 9 pounds per gallon is specified. After the casing has been cut off below the ground level, any void at the top of the casing must be filled with cement. If a metal plate is welded over the top of the casing, a weep hole is placed in the plate. A permanent abandonment marker is required on all wells unless otherwise requested by the SMA. This marker pipe is usually at least 4 inches in diameter, 10 feet long, 4 feet above the ground, and embedded in cement. The pipe must be capped with the well identity and location permanently inscribed.

The SMA is responsible for establishing and approving methods for surface rehabilitation, and determining when this rehabilitation has been satisfactorily accomplished. With satisfactorily rehabilitation, a Subsequent Report of Abandonment is approved, and the well bond is released.